Adams, Hope

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Cc: PSC_Contact; Besley, Sharon
Subject: RE: Hearing Exhibit 19 -- (Cross Examination Exhibit No. 4 Srunk) -- DN 2020-263-E
Attachments: DEC DEP Strunk Cross Exhibit 4.PDF

Parties:

Attached is a copy of the Cross Examination Exhibit regarding the Witness on the stand.

Jo Anne

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016	)))	ORDER ESTABLISHING STANDARD RATES AND CONTRACT TERMS FOR QUALIFYING FACILITIES

HEARD: Tuesday, February 21, 2017, at 9:00 a.m.; Tuesday, April 18, 2017, at 9:30 a.m.; Wednesday, April 19, 2017, at 9:30 a.m.; Thursday, April 20, 2017, and 9:30 a.m.; Friday, April 21, 2017, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

APPEARANCES:

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Tim R. Dodge, Lucy E. Edmondson, Heather D. Fennell, and Robert B. Josey, Jr., Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: This is the 2016 biennial proceeding held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 18 U.S.C. 824a-3, and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions, which delegated to this Commission certain responsibilities for determining each utility's avoided costs with respect to rates for purchases from qualifying cogenerators and small power production facilities. These proceedings also are held pursuant to G.S. 62-156, which requires this Commission to determine the rates to be paid by electric utilities for power purchased from small power producers as defined in G.S. 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by FERC prescribe the responsibilities of FERC and of state regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring the purchase and sale of electric power by electric utilities to cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards can become "qualifying facilities" (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain QF status. For such purchases, electric utilities are required to pay rates that are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against cogenerators or small power producers. FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.

With respect to electric utilities subject to state jurisdiction, FERC delegated the implementation of these rules to state regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to FERC's rules. The Commission implements Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate utility-specific avoided cost rates to be paid by the electric utilities to the QFs with which they interconnect. The Commission also has reviewed and made determinations regarding other related matters involving the relationship between the electric utilities and such QFs, such as terms and conditions of service, contractual arrangements, and interconnection charges.

HOUSE BILL 589

This proceeding also is a result of the mandate of G.S. 62-156, which was enacted by the General Assembly in 1979. This statute, as it was effective when the Commission established this proceeding, provided that "no later than March 1, 1981, and at least every two years thereafter" the Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed therein. The definition of the term "small power producer," for purposes of G.S. 62-156, as in effect when the Commission established this proceeding, was more restrictive than the PURPA definition of that term, in that G.S. 62-3(27a) included only hydroelectric facilities of 80 megawatts (MW) or less, thus excluding power producers using other types of renewable resources. While this matter was pending before the Commission, the General Assembly enacted House Bill 589, amending G.S. 62-3(27a) and G.S. 62-156, and enacting G.S. 62-110.8, which establishes a program for the competitive procurement of energy and capacity from renewable energy facilities.

PROCEDURAL BACKGROUND

On June 22, 2016, the Commission issued an Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Hearing. Pursuant to that Order, Duke Energy Carolinas, LLC (DEC); Duke Energy Progress, LLC (DEP); Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (Dominion); Western Carolina University (WCU); and New River Power and Light Company (New River) were made parties to these proceedings.

The following parties timely filed petitions to intervene that were granted: North Carolina Sustainable Energy Association (NCSEA); Public Works Commission of the City of Fayetteville; Carolina Utility Customers Association, Inc.; Carolina Industrial Groups for Fair Utility Rates I, II, and III; Southern Alliance for Clean Energy (SACE); Strata Solar, LLC; North Carolina Pork Council; NTE Carolinas Solar, LLC; Cypress Creek Renewables, LLC (Cypress Creek); O_2 EMC, LLC; and North Carolina Electric Membership Corporation (NCEMC). Participation of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On April 11, 2017, the North Carolina Attorney General's Office gave notice of intervention pursuant to G.S. 62-20.

On November 15, 2016, DEC and DEP (Duke) and Dominion (collectively, the Utilities) each filed their initial comments, statements, and exhibits. On November 28, 2016, WCU and New River filed proposed avoided cost rates.

On December 20, 2016, NCSEA filed a Motion to Strike as irrelevant certain materials in the Utilities' initial comments, which was denied by Commission order issued on January 18, 2017.

On December 22, 2016, the Public Staff filed a Motion for Amended Procedural Schedule. Similar to Duke's request included in its initial comments, the Public Staff requested an evidentiary hearing in this proceeding, and requested modifications to the procedural schedule. On December 30, 2016, the Commission issued an Order Scheduling Evidentiary Hearing and Amending Procedural Schedule, granting Duke and the Public Staff's requested evidentiary hearing and modifying the procedural schedule in this proceeding.

On January 17, 2017, DEC and DEP filed confidential avoided cost information.

On or after February 13, 2017, 900+ consumer statements of position were filed in this docket.

On or before February 15, 2017, all electric utility companies filed Affidavits of Publication of Notice of Public Hearing as required by the Commission's June 22, 2016 Order. The public hearing was held on February 21, 2017, as scheduled. Twelve witnesses testified at the public hearing.

On February 21, 2017, Dominion filed the direct testimony of J. Scott Gaskill and Bruce Petrie, and Duke filed the testimony and/or exhibits of Lloyd Yates, Kendal Bowman, Glen Snider, John Holeman, III, and Gary Freeman.

On March 28, 2017, NCSEA filed the testimony and exhibits of Carson Harkrader, Ben Johnson, and Kurt Strunk; Cypress Creek filed the testimony of Patrick McConnell; and SACE filed the testimony and exhibits of Thomas Vitolo, Ph.D.; and the Public Staff filed the testimony and exhibits of John Hinton, Jay Lucas, and Dustin Metz. Also on March 28, 2017, NCEMC filed initial comments.

On April 10, 2017, Dominion filed the rebuttal testimony of witnesses Gaskill and Petrie, and Duke filed the rebuttal testimony of witnesses Bowman, Snider, Holeman, and Freeman.

On August 8, 2017, Duke and Dominion jointly filed a motion, requesting that the Commission take into consideration Session Law 2017-192 (S.L. 2017-192 or HB 589) as additional authority in deciding the legal and policy issues in this proceeding. The Commission concludes that this motion should be granted. As reflected in the discussion and conclusions in this order, the Commission considered the authority enacted by S.L. 2017-192 in determining the issues in this proceeding.

In addition to the foregoing, there were other motions, orders, and filings not specifically mentioned which are matters of record.

Based on the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

1. The economic and regulatory circumstances facing QFs and electric public utilities in North Carolina have changed since the Commission's last biennial review of standard avoided costs rates.

2. For nonrenewable QFs, it is appropriate for DEC, DEP, and Dominion to be required to offer long-term levelized capacity payments and energy payments for ten year periods as a standard option to all QFs contracting to sell one MW or less capacity. The standard levelized rate option of ten years should include a condition making the contracts under that option renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration.

3. It is appropriate for DEC, DEP, and Dominion to be required to offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (1) participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

4. Dominion should continue to offer in its Schedule 19-LMP, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the Commission's Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued on December 19, 2007, in Docket No. E-100, Sub 106 (Sub 106 Order), except as modified by this order.

5. For nonrenewable QFs, when calculating avoided capacity rates using the peaker method, it is appropriate to require a payment for capacity in years of a utility's integrated resource planning (IRP) forecast period when a capacity need is demonstrated

during that period; however, providing a levelized capacity payment over the term of the contract is a reasonable means of implementing this capacity payment.

6. It is appropriate for the utilities to continue to evaluate the capacity benefits of QF generation and to make other changes as needed to accurately reflect the avoided capacity benefits provided by QF generation of all resource types over the short and long run.

7. The availability of a combustion turbine (CT) is not determinative for purposes of calculating a Performance Adjustment Factor (PAF), because the fixed costs of a peaking unit under the peaker methodology employed by the Commission are a proxy for the capacity-related portion of the fixed costs of any avoided generating unit.

8. It is appropriate to require DEC, DEP, and Dominion to utilize a PAF of 1.05 in their respective avoided cost calculations for all QFs, other than hydroelectric QFs without storage capability, and to utilize a PAF of 2.0 in their respective avoided cost calculations for hydroelectric QFs with no storage capability and no other type of generation until discontinued by further order of the Commission or in accordance with the stipulation filed by DEC, DEP, and the NC Hydro Group and the Commission's December 31, 2014, Order in Docket No. E-100, Sub 140 (Sub 140).

9. DEC and DEP's proposed seasonal allocation weightings of 80% for winter and 20% for summer are appropriate for use in weighting capacity value between winter and summer, and should be used in calculating DEC and DEP's avoided capacity rates in this proceeding.

10. It is not appropriate for DEC and DEP to reset energy prices under the standard offer contract every two years at this time.

11. It is appropriate to require DEC and DEP to recalculate their avoided energy rates using forward natural gas prices for no more than eight years before using fundamental forecast data for the remainder of the planning period.

12. The input assumptions used by Dominion for the purpose of determining its proposed avoided energy rates, including the avoided costs related to fuel hedging activities, are appropriate for use in this proceeding.

13. An imminent violation of a North American Electric Reliability Corporation (NERC) BAL Standard is a system emergency, as defined in 18 CFR 292.101(b)(4); therefore, it is appropriate for DEC, DEP, and Dominion to curtail PURPA QFs when a NERC BAL Standard violation is imminent.

14. It is appropriate for DEC and DEP to amend their standard offer contract to incorporate the imminent violation of a NERC BAL Standard into the system emergency provision.

its rules for the competitive procurement of renewable energy and implement that program in a manner that provides the certainty that Utilities and QFs need.

The Commission further concludes, based upon the foregoing and the entire record herein, that it is appropriate for Dominion to continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, including the payment of capacity credits based on the PJM Reliability Pricing Model (RPM), subject to the same conditions as approved in the Sub 106 Order and most recently restated in the Order on Inputs, except as modified by this order.

Finally, the Commission finds good cause to make clear that the conclusions reached in this section apply equally to hydroelectric QFs without storage capacity (commonly called run-of-the-river hydro facilities). DEC and DEP filed Schedules PP-H and PPH-1, respectively, in which they proposed standard offer fixed rates available to run-of-the-river hydro QFs that are 5 MW and less for 5-, 10-, and 15-year terms, reflecting the terms and conditions of the Hydro Stipulation, which was filed and approved in Docket No. E-100, Sub 140. In doing so, Duke relied on the State policy set forth in G.S. 62-156 and the Commission's approval of the Hydro Stipulation. The Commission has historically relied on this State policy supporting small hydro facilities and the relatively small and finite amount of small hydro capacity in the state, as justification for treating these QFs differently than other QFs. However, these provisions were repealed or substantially amended by the enactment of S.L. 2017-192, undermining the policy rationale that prompted the Commission to approve the Hydro Stipulation in the Order on Inputs. Therefore, the Commission concludes that G.S. 62-156 requires that run-of-the-river hydro QFs be treated similarly to other QFs with regard to the Commission's implementation of the standard offer contract.

Based on foregoing and the entire record in this proceeding, the Commission finds that it is appropriate to require the Utilities to offer as a standard option long-term levelized capacity payments and energy payments for ten-year periods to all QFs contracting to sell one MW or less capacity.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 5 AND 6

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Snider; Dominion witnesses Gaskill and Petrie; Public Staff witness Hinton; NCSEA witness Johnson; Cypress Creek witness McConnell; and SACE witness Vitolo.

Duke witnesses Bowman and Snider testified in support of Duke's proposal to calculate capacity costs taking into account each utility's relative need for additional generating capacity as determined by their respective IRPs. Witnesses Bowman and Snider both testified that PURPA requires that QFs be fairly and reasonably compensated for the incremental capacity and energy costs that, but for capacity and energy provided by the QF, the utility would be forced to generate or purchase elsewhere to serve its customers. If the purchase of power from a QF does not, in part or in total, avoid the utility's need to incur incremental capacity and energy expense, then the QF should not be compensated for providing that benefit. In support of her testimony, witness Bowman cited FERC's decision in Ketchikan, holding that while a utility is legally obligated to purchase energy or capacity provided by a QF, the purchase rate should include only payments for energy or capacity that the utility can use to meet its total system load.[3] She also cited N.C. Gen. Stat. § 62-156(b)(2), providing that "a determination of the avoided energy costs to the utility shall include . . . the expected costs of the additional or existing generating capacity which could be displaced." Witness Bowman acknowledged that the Commission has cited FERC's Hydrodynamics decision,[4] as supporting its determination that the Utilities should not include zeros in the early years when calculating avoided capacity rates. She distinguished Hydrodynamics from the circumstances of this proceeding, noting that Hydrodynamics pertained to a limit on installed capacity purchases by a utility and not to a utility proposal to recognize a capacity value only in years where the utility's IRP showed a need for such capacity.

Witness Snider also recommended that the Companies' relative need for incremental generating capacity should be accounted for in calculating its avoided capacity rates, arguing that prior to the year in which the next generation unit is needed to serve system load, the utility does not have a capacity need to avoid. Thus, witness Snider testified, the calculation of the capacity portion of the avoided cost rate should not ascribe value for years prior to the first avoidable capacity need. Witness Snider further testified that the first capacity need for both Duke utilities occurs in the 2022-2023 timeframe, as shown in their 2016 IRPs. He also testified that QFs under the standard offer tariff will receive capacity payments in years prior to the Companies' first capacity need because the QFs will receive a levelized capacity rate reflecting a lower annual payment to account for those initial years in which there is no avoidable capacity costs. Witness Snider concluded that this proposal is fair to Duke's customers because with this adjustment, the Duke utilities' customers would only be paying QF capacity payments equal to the economic value of an associated avoided capacity cost.

Dominion witnesses Gaskill and Petrie testified in support of Dominion's proposal to include no payment for capacity with its standard offer avoided cost rates. Witness Gaskill testified that, even if Dominion did have a near-term need for additional generation capacity in North Carolina, which it does not, additional distributed solar generation beyond what is already under contract would not allow Dominion to avoid future capacity expansions. In support of his argument, he testified that FERC has clearly stated that while utilities may be obligated under PURPA to purchase from QFs, an avoided cost rate need not include payment for capacity where a QF does not allow the purchasing utility to avoid building or buying future capacity—that, when a utility's demand for capacity is zero, the cost for capacity may also be zero. Further, he testified that FERC's rules implementing PURPA define avoided costs as the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from a QF, the utility

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[3] See City of Ketchikan, Alaska, 94 FERC ¶ 61,293 (2001) (Ketchikan).

[4] Hydrodynamics, 146 FERC ¶ 61,193 (2014) (Hydrodynamics).

would generate itself or purchase from another source. He stressed the importance of the "but for" language in that definition in the context of capacity payments, noting that it is not the case that, "but for" the distributed solar QFs on its North Carolina system, Dominion would purchase or self-supply capacity. He concluded that, because it will not avoid capacity need due to incremental distributed solar generation in North Carolina, a capacity rate of zero accurately reflects Dominion's actual avoided costs for QF contracts signed today. He testified that unlike previous QFs interconnecting at distribution level that acted as load reducers and, by reducing Dominion's load obligation, deferred the need to buy or construct new capacity, because distributed solar generation now exceeds load in this area, there is no need for additional distributed solar in Dominion's North Carolina service area, and that because incremental distributed solar QF generation in North Carolina will not allow it to avoid capacity need, a zero capacity payment accurately reflects Dominion's actual avoided costs for QF contracts signed today.

Witness Petrie testified that several factors support this proposal. First, he testified that Dominion's 2016 IRP showed no capacity need until 2022 at the earliest, and that its preliminary updated load forecast as of December 2016 pushes that need for incremental capacity out to 2024. He further testified that the most recent PJM load forecast from January 2017 shows no need for capacity for Dominion until after the 2026 timeframe. Additionally, witness Petrie testified that, even if a need for new capacity did exist within Dominion's current long-term planning horizon, because its North Carolina service area is saturated with distributed solar QF projects, any new distributed solar generation added going forward will have little to no peak load reducing effect on the system. He testified that new solar QFs are not effective substitutes for new dispatchable generation, such as a CT, unless they are located near areas with increasing load growth and where additional generation is needed to reduce congestion and improve reliability. However, he testified that this is not the case for solar QFs in Dominion's North Carolina territory because while previous QFs interconnecting at the distribution level acted as load reducers, deferring the need for new capacity, distributed solar generation now exceeds load in the North Carolina service area, such that there is no more load to offset. For similar reasons, he noted, additional distributed solar in this area will not improve overall system reliability, especially with regard to meeting wintertime peak demands. Considering all of these factors, witness Petrie concluded that Dominion cannot avoid building or buying capacity by purchasing from new distributed solar generation in its North Carolina service area. Witness Petrie also testified that Dominion is considering the addition of aeroderivative CTs as quick-start, flexible units that can balance the system as more intermittent, non-dispatchable solar generation resources are added. However, because these aeroderivative CTs have a higher installed cost than the large frame turbines that Dominion has built since the year 2000 (an estimated 67% more than other CTs), their addition will result in increased long-term capacity costs for customers.

Witness Petrie further testified that pricing for solar generation should reflect its lack of dispatchability and limited usefulness during system emergencies. He testified that FERC's rules list several factors that should be considered when determining avoided cost rates for QFs including, among other factors, the availability of a QF's energy or capacity, the utility's ability to dispatch the QF, the QF's expected or demonstrated reliability, and the usefulness of the QF's energy and capacity during system emergencies. Witness Petrie also noted his understanding of FERC's recent explanation that its rules permit state regulatory authorities to consider factors such as capacity availability, dispatchability, reliability, and the value of energy and capacity when determining avoided cost rates, and, based on these factors, to set lower rates for purchases from intermittent QFs than for purchases from firm QFs. Witness Petrie also cited recent changes to PJM's capacity market rules as further evidence that additional distributed solar generation in Dominion's North Carolina service area is not the type of reliable capacity that would allow it to avoid capacity needs. He testified that these rule changes were intended to better reflect the changing resource mix in PJM, including the growing volume of intermittent generation, and to better align resource payments to performance. He noted that intermittent resources are particularly challenged under the new rules, as they can be subject to severe penalties for non-performance during summer and winter peak hours. He also pointed out that PJM training materials issued after FERC approved the new rules suggest that an acceptable offer for a 100-MW nameplate solar facility would be from 0 to 20 MW of firm capacity. He concluded that these changes demonstrate that solar capacity, as compared to the firm capacity of a dispatchable and reliable CT, is not capable of sustained, predictable operation during emergency conditions, and has limited value in the new PJM capacity market, from which Dominion's actual avoided costs are derived.

Witness Petrie also testified that Dominion, which has experienced winter peaks in two of the last three years, as well as PJM, have increased their focus on planning for winter reliability, the costs for which include procuring fuel supply backup, additional gas pipeline capacity, and improved winter testing and operations. He noted that the spikes in demand during periods of extreme cold over the last several years show the volatility of winter peak loads and the need for dispatchable generation on the system. He noted also that because solar generation output is near zero at 7 a.m. on cold winter mornings when these system peaks occur, a CT is still required in the winter.

Finally, witness Petrie testified that the addition of large amounts of distributed solar resources is likely to shift the time of the summer peak to a later hour in the day, while not impacting the timing of the winter peak load due to their minimal output at that time. He noted that, when Dominion reaches the threshold of aggregate solar additions of about 1,000 MW across its North Carolina service area, the summer peak hour is expected to shift from 5 pm to 6 pm or later. Witness Petrie testified that, as the summer peak hour shifts later in the day, any additional solar generation produces less summer peak load reducing effect, and is thus less effective in deferring or avoiding the next required capacity resource because solar output decreases in the later hours of the evening and, therefore, has lower capacity value. The marginal value of solar capacity, therefore, decreases as more solar generation is added to the system. Witness Petrie concluded that Dominion's proposal to make no capacity payments to QFs receiving the standard offer accounts for the fact that, due to all of these factors, additional North Carolina QF solar resources will not allow it to defer or avoid capacity needs. This proposed modification would also, he stated, avoid burdening customers with avoided cost payments that exceed Dominion's actual avoided costs. Witness Petrie concluded that given these considerations and the factors described in his direct testimony, the appropriate capacity rate for new QFs located in this area is zero cents per kWh for the duration of the standard offer contract.

Witness Petrie testified that SACE witness Vitolo's assertion that as a PJM member, Dominion only has summer capacity needs, is incorrect and oversimplified. He testified that the PJM capacity market reflects the need for capacity planning to meet both summer and winter peaks, since under its new capacity market rules, PJM generators must provide reliable capacity during all months of the year. He disagreed that PJM has a surplus of winter capacity, citing the shortage of available generation during the winter of 2014 that demonstrated the need for the new rules. He also testified that since solar resources have little or no capacity to generate at the winter morning peak, they are subject to significant capacity performance penalties if they bid into this market, since under the new rules they are subject to the same financial penalties that apply to conventional fossil-fueled resources for non-performance on critical days. Witness Petrie also testified that the 38% capacity value cited by witness Vitolo denotes capacity injection rights, not the market capacity value, of solar resources. He emphasized that, on a risk adjusted basis, the capacity credit of a solar resource offered into PJM's capacity market is in the nameplate capacity range of 0 to 20% (based on PJM's assumption that a typical solar facility may provide 38% in the summer, but only 2% in the winter). Whether a solar generator bids into the PJM market at 0 or 20% depends on how much penalty risk the generator is willing to accept. He testified that this reduced capacity credit percentage, combined with the potential penalties, demonstrates that, from a reliability perspective, solar resources can only be counted on for a small portion, if any, of their nameplate capacity, and that continuing to pay new solar QFs rates for avoided capacity, when they do not defer or avoid any capacity need, results in an overpayment beyond Dominion's actual avoided costs.

Witness Petrie also addressed Duke's proposal to include zeros in the calculation of the capacity rates for the years where the utility does not have a capacity need. He stated that, in the event that the Commission declines to accept Dominion's proposal to set capacity rates to zero for the duration of the standard offer contract, Dominion would agree with Public Staff witness Hinton's conclusion that Duke's proposal is reasonable and appropriate. He testified that while Duke's proposal would still result in Dominion overpaying QFs, it would come closer to valuing the capacity appropriately over the course of a long-term PPA than would paying a QF for capacity over the entire term, including for years in which there is no demonstrated need.

Witness Petrie agreed with witness Hinton that in the current circumstances it is appropriate for the Commission to reconsider this issue, since the traditional application of the peaker method is resulting in overpayment in excess of actual avoided costs and is not sending proper price signals to the market. He noted that there is historical precedent for the Commission allowing the utility to pay zero for capacity during the front years of a QF contract, citing orders issued in the 1994, 1996, and 1998 avoided cost proceedings in which the Commission recognized that, where no capacity costs are avoided, no capacity credit should be reflected in the capacity rate calculation. He stated that the evidence in this case is analogous to those proceedings.

Witness Petrie disagreed with NCSEA witness Johnson's argument that paying QFs for capacity only when the utility actually shows a capacity need discriminates against QFs. Witness Petrie testified that, as a regulated utility, Dominion has an obligation under the law to serve its customers reliably and at least cost. He testified further that North Carolina QFs cannot defer or avoid the need for new capacity because they do not reduce load on Dominion's system. He testified that paying for capacity when it is not needed or avoided contradicts the PURPA requirement that the rates a utility pays for QF output should not exceed the utility's avoided costs. He also testified that, contrary to witness Johnson's assertion, the principle of ratepayer indifference is also violated if customers pay the QF for capacity that is not actually avoided, because those customers are paying for something they do not receive. He noted that the determination of avoided costs and rates to be made in this proceeding is not a theoretical exercise, but instead represents real customer costs.

Finally, witness Petrie testified that, contrary to witness Vitolo's testimony, the circumstances of the Ketchikan case, in which he understood FERC to have found that if the utility does not have a demonstrated capacity need it should not be required to pay for incremental QF capacity, are similar to the current situation in North Carolina. He noted that as shown in Ketchikan, Dominion also currently has no near-term incremental capacity needs. He acknowledged that in the 2014 biennial proceeding, the Commission cited FERC's later Hydrodynamics decision in support of its determination in that docket that the Utilities should not include zeros for capacity in the early years when calculating avoided capacity rates. He testified that the situation in Hydrodynamics differed from the circumstances at issue in Ketchikan and those at issue in this proceeding, because it addressed a utility proposal to limit installed capacity purchases with no connection between that limit and the utility's own actual need. He noted that, in Hydrodynamics, FERC reiterated its earlier conclusion that when a utility's demand or need for capacity is zero, avoided cost rates need not include capacity cost. He stated that such is the case here, and therefore that the Ketchikan rationale does apply to this case and to Dominion's proposal.

Dominion witness Petrie clarified that it was not relevant that Dominion used the differential revenue requirement (DRR) method of determining avoided costs during the 1990s cases in which the Commission recognized that no capacity credit should be included where no capacity costs are avoided. He testified that, regardless of avoided cost methodology, if there is no demonstrated capacity need, the utility should not be required to pay for capacity. He agreed that all three traditional avoided cost methodologies have the same purpose: reasonably estimating the utility's future avoided cost.

Dominion witness Gaskill testified that the number of QF PPAs and related capacity that Dominion has entered into increased from 72 PPAs and 500 MW of capacity as of the date of his direct testimony to 76 PPAs and 521 MW of capacity as of the hearing date. Witness Gaskill also answered questions from NCSEA counsel comparing the amount of distributed solar generation on Dominion's North Carolina system as described in his testimony to the amount of solar generation either connected to its system or having an executed Interconnection Agreement that was identified in its February 1, 2017 interconnection queue report filed in Docket No. E-100, Sub 101A (and entered as NCSEA-Dominion Cross Exhibit 1). He clarified that the queue report is prepared by Dominion's interconnection team from which he operates separately. He testified, however, that the 435 MW of operational solar capacity noted in his testimony is consistent with the 345 MW of operational interconnected solar capacity reflected in the queue report, because the 435 MW total includes 90 MW of solar that is in the PJM wholesale interconnection queue, but is interconnecting to Dominion's distribution system. Similarly, he testified that the difference between his estimate of 363 MW in study phase as shown in Figure 2 to his direct testimony, and the 282 MW designated as Project A, Project B, or "Subordinate" in the queue report, is also likely due to his Figure 2 including PJM queue projects. He also noted that the total MW reflected by the queue report as "connected" and "IA executed" projects—519 MW—is comparable with his updated testimony that Dominion has entered into PPAs for 521 MW of solar capacity.

Witness Petrie testified that Dominion occasionally enters into contracts for capacity outside of QF agreements, and recently acquired replacement capacity related to the March 2017 deactivation of the Roanoke Valley Power facility (ROVA), some of which it filled through short-term capacity purchases in the PJM market. Witness Gaskill testified that the term of the contract for Dominion's purchases from this facility extended through mid-2019, but because the facility deactivated, Dominion was obligated to locate capacity to replace what that facility had committed through PJM's wholesale capacity market. He testified that Dominion is self-supplying the remainder of the capacity previously supplied by this facility. Witness Petrie agreed in response to questions by counsel for SACE and the Public Staff that Dominion engages in generation and transmission planning on a system wide basis, including North Carolina and Virginia.

Witness Gaskill further testified that, generally speaking, non-wholesale contracts, such as a contract for a QF selling under PURPA, would not be eligible to replace a capacity commitment by being bid directly into the PJM wholesale capacity market, because they are not participants in that market. Specifically as to the ROVA facility, he testified that because that facility had been committed into the PJM capacity market as a capacity performance resource, eligible replacement capacity had to be located in that market, and behind the meter QF solar generation would not have qualified as eligible replacement capacity for a capacity performance resource. He noted that the potential capacity value that can be derived from solar QFs is not from their generation of power but from their load reducing effect, because as they reduce the peak load over time, they reduce the amount of capacity Dominion must procure through PJM. But, as shown in this case where this generation exceeds the load requirements, there is no load reducing effect and no impact on PJM capacity market procurement. Witness Gaskill also clarified that as an alternative to putting power to Dominion as a QF, a developer could become a PJM market participant and sell its output into PJM. Witness Gaskill confirmed that in response to a Public Staff discovery request he reconstructed Figure 1 from Dominion's

Initial Filing, which had shown the tremendous recent growth in QF solar development in its North Carolina service area since 2013, to show the current level of QF solar development on the North Carolina portion of Dominion's system compared to its system average on-peak load.

Public Staff witness Hinton testified regarding the traditional application of the peaker method and its valuing of capacity over the entire planning period. He stated that according to the theory of the peaker method, the utility's generating system is operating at the optimal point, the capital cost of a peaker (based on a CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided costs. He noted that in reality, however, no utility system operates at the most optimal point and utility planners have to deal with unexpected changes in load, fuel costs, and other factors that challenge optimality. He expressed concerns that the rapid and substantial increase in QF development raises doubts as to whether the traditional application of the peaker method would continue to be appropriate and provide the market with a correct price for capacity. He further noted that an end result of the traditional long-run application of the peaker method is that every kilowatt-hour (kWh) generated during on-peak hours provides capacity value and this value is quantified from the first day of QF operation, regardless of the utilities' short-run needs for additional capacity.

Witness Hinton further testified that contrary to the position taken by the Public Staff in prior proceedings regarding the use of zero capacity value in certain years, he believed that in light of current circumstances related to the amount of solar generation online and pending in the interconnection queue, it is appropriate for the utilities to adjust their avoided cost rates to provide a capacity payment to new QFs only when additional capacity is needed on the system. He further stated that by restricting the inclusion of a capacity credit until the IRP has established a capacity deficiency, the risk of overpayment by ratepayers is reduced, while providing a reasonable level of financial compensation for avoided capacity costs and sending a better price signal to the market.

Witness Hinton indicated that the Public Staff supports Duke's proposal to limit capacity payments until the IRP dictates a capacity need in this proceeding, but that conditions in future proceedings may lend to reconsideration of this issue, as well as the continued applicability of the peaker method. Witness Hinton noted that DEC indicates a resource need of approximately 3,903 MWs over the planning period (2017-2031), with the first resource need in the 2022/2023 timeframe, and DEP indicates a resource need of approximately 4,071 MWs over the same planning period, with the first resource need in 2021/2022.

With regard to Dominion's position that the existing and projected level of solar generation exceeds the load in its North Carolina service territory such that there are no more capacity costs to be avoided with additional QF generation, witness Hinton testified that Dominion's proposal seems to run counter to general principles of utility system planning. Witness Hinton testified that utility planning is not performed on a state-by-state basis; rather, the generation and transmission systems are planned on a system-wide basis. This system perspective is applied in various regulatory proceedings, including IRP proceedings, where witness Hinton noted that Dominion's 2016 IRP indicates a capacity need of approximately 4,457 MW, with the first resource need in 2022. In addition, witness Hinton testified that one of the central arguments in Dominion's application to join PJM was that Dominion's membership would make the utility part of a vast integrated transmission system with interfaces with PJM-East, PJM-West, and AEP with greater access to generation resources, load diversity, and improved reserve sharing across the region. Witness Hinton disagreed with Dominion's argument that there is no capacity value associated with incremental QF generation. He therefore recommended, like DEC and DEP, that the Commission require Dominion to provide a capacity credit based on the first indicated need in its IRP.

NCSEA witness Johnson testified in opposition to the Utilities' proposal to include payments for avoided capacity only for those years when the utility's IRP shows a capacity need. Witness Johnson testified that Dominion's proposal results in the payment of no avoided capacity rate and that the DEC and DEP proposal results in an approximate 60% reduction in the avoided capacity rate from the 2014 rate. He further testified that the Commission rejected this same proposal by DEC and DEP in the 2014 biennial avoided cost proceeding, observing that: 1) DEC and DEP justified their proposal in 2014 on the same or similar bases on which they justify the 2016 proposal; and 2) that the Commission should reject the proposal again, as it did in 2014. In addition, witness Johnson testified that the use of zeros is inconsistent with the fundamental goals of PURPA, as well as the most appropriate interpretation of the concepts of "incremental cost" and "avoided cost." He also testified that the use of zeros is inconsistent with the concept of "ratepayer indifference," and it leads to undue discrimination against QFs. Witness Johnson testified that, in general, the goals of PURPA are best promoted when PURPA is implemented in a way that focuses on long run incremental cost, rather than a short run measure of cost that excludes capacity costs. More specifically, he testified that QF avoided cost rates should reflect the full long run cost of building and operating the utilities' generating facilities, including years when new generating units are not being added. He further testified that because of economies of scale, electric utilities typically find it cost effective to construct large generating facilities, at multi-year intervals. He testified that if the utility has a capacity need of 100-MW per year over a 6-year period, it will not add a 100-MW plant every year but instead will add a 600+ MW plant in a single year. Under these circumstances, Johnson argued that economic theory tells us there are long run capacity costs present in every year; they are not zero in some years and present in others. Put a different way, Johnson testified that given reality of how electric utilities add new generating capacity, even during years when "zero" capacity is planned, the long run cost of capacity is the same, or nearly the same as it is during other years, when a new block of capacity is scheduled to be placed into service. With respect to discrimination against QFs, NCSEA witness Johnson testified that PURPA specifically states that QF rates must not "discriminate against qualifying cogenerators or qualifying small power producers." He explains that under rate base regulation, the utilities are allowed to recover the cost of new generating capacity as they are completed and put into commercial operation, even though some of the capacity is being added prior to the time it is required (due to lumpiness). He testified that since the utility is allowed to recover its capacity costs during the "zero" years just after a new capacity addition and its reserve margin is higher than the required minimum, to avoid discrimination, the QF should be treated the same.

SACE witness Vitolo testified in response to the Utilities' proposal to eliminate capacity payments in years when the utility's IRP shows no need for capacity. He testified that the use of a dollar-per-kilowatt cost of a CT under the peaker methodology and the making of a capacity payment in every year are "inextricably linked." This link, he testified, results from the assumption that the utility's generating system is operating at equilibrium and that generation capacity payments will be made for all years in which the QF is in service. He further testified that the concerns expressed in the Sub 140 proceeding are still applicable today. Those concerns, he testified, prompted the Commission to reject the same proposal in the Order on Inputs. Witness Vitolo also testified in response to Dominion's proposal to eliminate capacity payments, arguing that, for similar reasons the Commission should reject this proposal as well.

As amended by HB 589, G.S. 62-156(b)(3) provides that a future capacity need shall only be avoided in a year where the utility's most recent IRP has identified a projected capacity need to serve system load and the identified need can be met by the type of resource being used by the small power producer to generate electricity.

Discussion and Conclusions

With regard to QFs that are small power producers, the Commission concludes that G.S. 62-156(b)(3) requires that, when calculating avoided capacity rates using the peaker method, a utility's standard offer to purchase should include a capacity credit for those years when the utility's most recent IRP demonstrates a need for capacity. The Commission further concludes that Duke witness Snider's proposal to provide levelized capacity payments for the full term of the ten-year standard offer, including capacity payments in years prior to the utility's first capacity need reflecting a lower annual payment to account for those initial years in which there is no avoidable capacity costs, is a reasonable means of implementing this directive. More specifically, this tends to support PURPA's directive to encourage QF development by providing more revenue to the QF earlier in the term of the standard contract. Therefore, the Commission will require the Utilities to include this methodology in their respective standard offer to purchase tariffs as part of the compliance filing required by this order.

Based upon the foregoing and the entire record herein, the Commission determines that this avoided capacity payment methodology is also appropriate with regard to the standard offer to purchase available to QFs that are not small power producers. While the Commission has previously considered and rejected similar proposals in past avoided cost proceedings, the Commission finds that the changed economic and regulatory circumstances facing QFs and utilities now justifies accepting this change. PURPA requires that QFs be fairly and reasonably compensated for the incremental capacity and energy costs that, but for the capacity and energy provided by the QF, the utility would be required to generate or purchase elsewhere to serve its customers, but PURPA was not intended to force a utility and its customers to pay for capacity that it otherwise does not need. Changes experienced in the marketplace for QF-supplied power in North Carolina challenge many of the assumptions regarding the application of the peaker method, as well as threaten to obligate customers to pay for capacity well in excess of what may actually be avoided. While the Utilities' IRPs all continue to show additional need for capacity, the mere presence of QF capacity, including solar nameplate capacity, does not always translate into an avoidance of capacity needs by the utility. FERC's regulations implementing PURPA provide that states shall consider a number of factors in determining avoided costs, including the availability of capacity or energy from a QF during the system daily and seasonal peak loads (including dispatchability, reliability, and the individual and aggregate value of energy and capacity from QFs), as well as the relationship of the availability of energy and capacity from the QF to the ability of the utility to avoid costs. 18 C.F.R. 292.304(e). These factors are largely consistent with the directives in G.S. 62-156, and the Commission concludes that the operating characteristics of a QF resource must be considered in evaluating whether the QF can help to avoid the utility's planned capacity addition. In considering these characteristics and the other factors, the Commission concludes that the record in this proceeding demonstrates that the capacity value provided by additional solar PV does not necessarily help the utilities to offset or avoid their next capacity need. Solar QFs may provide some seasonal capacity benefit, but may also create other operational challenges due to its non-dispatchability and intermittency that offset the capacity benefits.

In light of these specific directives to consider dispatchability, reliability and other factors in determining avoided costs, the Commission is not persuaded by SACE witness Vitolo and NCSEA witness Johnson's arguments that inclusion of no capacity value in avoided capacity rates when the utility's IRP does not show a need is discriminatory under PURPA. As discussed in detail above, the testimony of the Utilities' and the Public Staff's witnesses demonstrates that the decision to allow a utility to add its owned generation resources to its portfolio and recover the costs is too different from the PURPA must-purchase requirement to make this a useful analogy.

However, the Commission agrees with NCSEA witness Johnson that the appropriate analysis of capacity needs should be conducted over the long run, and the use of zeroes in the early years will have the effect of lowering the avoided cost rates for the entire period. The Commission finds that this outcome may provide avoided cost rates that more accurately reflect the cost being avoided by the Utilities, in light of the amount of current and pending growth from QFs in North Carolina. As Public Staff witness Hinton testified, by including a capacity credit only in those years in which the IRP has established a capacity deficiency, the risk of overpayment by ratepayers is reduced, while providing a reasonable level of financial compensation for avoided capacity costs and sending a better price signal to the market. Further, the Commission agrees with witness Johnson that the Utilities should focus on improving the rate design in ways that are responsive to the specific concerns that have been identified to ensure that the change in policies being adopted in this proceeding do not adversely impact other small power producers, including wind, methane from landfills, hog or poultry waste, and non-animal biomass, for problems that are specifically related to solar energy. As discussed in other sections of this order, the Commission concludes that an avoided cost rate based on the characteristics of the QF-supplied power may also be appropriate going forward in future proceedings, and, therefore, will require the Utilities to include proposed rates and data sufficient for the parties and the Commission to evaluate the appropriateness of such a rate in their initial filings in the next biennial avoided cost proceeding.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 7 AND 8

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Snider; Dominion witness Petrie; Public Staff witness Hinton; NCSEA witness Johnson; and SACE witness Vitolo.

Summary of the Testimony

Duke Witness Snider testified in support of Duke's proposal to reduce the PAF multiplier for non-hydro facilities from 1.20 to 1.05 to align the PAF with the operational characteristics of a CT. Witness Snider testified that the PAF is intended to make up for a QF's unavailability during the on-peak period when QFs are paid for capacity by increasing the rate the QF is paid during peak hours to account for hours in which it does not operate. Witness Snider acknowledged that Duke's resources are sometimes unavailable, and it follows that the QFs replacing those resources should not be penalized for the same level of unavailability. He further testified that when using the peaker methodology to calculate avoided cost rates, the resource a QF is replacing is a CT. He then testified that DEC's and DEP's CT fleet performs at greater than 95% starting reliability, and as such, no PAF greater than 1.05 is warranted. Witness Snider acknowledged that the Commission declined to adopt a similar proposal in the Sub 140 proceeding, noting that the Commission determined that the arguments presented in that proceeding to modify the PAF were insufficient "at that time," and found "widespread QF development under the existing framework without adverse impacts to ratepayers." Witness Snider testified that since Sub 140, both DEC and DEP have experienced an unprecedented "surge" in solar QFs exposing customers to $1 billion in overpayments for energy and capacity. He testified that the approximately $1 billion in overpayments only accounts for QFs that are currently delivering power and does not include approximately 1,100 MW (of 5 MW and less QFs) that are in development or under construction and remain eligible for the avoided cost rates that were calculated in Sub 140 or Sub 136. He also testified that Duke is unaware of any other jurisdiction, except DEC's and DEP's stipulated avoided cost rates in South Carolina (which are derived from the rates calculated in Sub 140), that have recently explicitly or implicitly provided for a PAF multiplier in setting avoided capacity rates.

Witness Snider also responded to the Public Staff witnesses' testimony, recommending a PAF of 1.16 based on an average availability factor of 86.33%. He states that the Public Staff's focus on "availability" is appropriate, but their calculation has a critical flaw that leads to substantial overstatement of a just and reasonable PAF. In support of his argument he first defined a generator's "availability factor" as the amount operational data and marginal cost data on a season-specific basis, and consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable;

17. That WCU and New River's proposals to offer variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved ten-year, long-term avoided cost rates for QFs interconnected at distribution are approved. WCU's and New River's compliance filings shall reflect the changes the Commission has approved herein to DEC's proposed ten-year avoided capacity rates; and

18. That the proposed schedules, supporting calculations, and purchase power agreements and terms and conditions, except as specifically addressed in this order, are approved and shall be implemented.

ISSUED BY ORDER OF THE COMMISSION.

This the 11th day of October, 2017.

NORTH CAROLINA UTILITIES COMMISSION

Linnetta Threatt

Linnetta Threatt, Acting Deputy Clerk

Commissioners Bryan E Beatty and Don M. Bailey did not participate in this decision.